DIVISION FOR AIR QUALITY
DEPARTMENT FOR ENVIRONMENTAL PROTECTION
NATURAL RESOURCES AND ENVIRONMENTAL PROTECTION CABINET
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FRANKFORT, KENTUCKY 40601

REVISED

PRELIMINARY DETERMINATION AND STATEMENT OF BASIS ON THE APPLICATION OF

THOROUGHBRED GENERATING COMPANY, LLC
THOROUGHBRED GENERATING STATION

TO CONSTRUCT AND OPERATE A PULVERIZED COAL STEAM ELECTRIC GENERATING STATION

REVIEW AND ANALYSIS BY: Ben Markin

AFS NUMBER:	21-177-00077	SIC CODE:	4911
REGION:	Owensboro	COUNTY:	Muhlenberg
LOG NUMBER:	53619-20	DATE COMPLETE:	April 23, 2001
UTM COORDINATES:	4129.55N, 492.02E	TYPE OF REVIEW:	NSR, PSD, NSPS, Title V, Acid Rain, MACT, CAM

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1. EXECUTIVE SUMMARY

Thoroughbred Generating Company, LLC submitted a revised permit application dated October 26, 2001, to construct and operate a Pulverized Coal steam electric generating station in Muhlenberg County, Kentucky. The construction will consist of two 7443 MM BTU/hr Pulverized Coal Boilers (PCB) which will operate with a total nominal output capacity of 1500 megawatts (MW). Each PCB is to be equipped with its own exhaust stack located within a common chimney and will be equipped for fuel oil start-up. Other facilities to be constructed will include Flue Gas Desulfurization (FGD) reagent, ash, and solid waste by product storage and handling equipment; an auxiliary boiler; two cooling towers; oil storage tank; an emergency generator; and two diesel and one electric powered fire pumps. The plant is to be permitted to operate 8760 hours per year for each unit. The proposed plant will be a major source as defined in Kentucky State Regulation 401 KAR 51:017 (40 CFR 52.21), *Prevention of Significant Deterioration (PSD) of air quality*. The potential emissions of regulated air pollutants including particulate matter (PM & PM10), sulfur dioxide (SO_2), nitrogen oxides (NO_x), carbon monoxide (CO) and volatile organic compounds (VOC) are in excess of 250 tons per year. Additionally, the emissions of volatile organic compounds (VOCs), fluorides as HF, mercury (Hg), beryllium (Be), and Sulfuric Acid (H_2SO_4) mist are subjected to PSD review since these emissions exceed the significant emission rates as presented in Regulation 401 KAR 51:017, Section 22.

The proposed plant will belong to one of the 28 major source categories listed in the PSD regulation, 401 KAR 51:017, because the PCBs will be used as indirect heat exchangers to produce electricity. Additionally, the source will be located in a county classified as "attainment" or "unclassified" for each of these pollutants pursuant to Regulation 401 KAR 51:010, *Attainment Status Designations*. Consequently, the proposed facility meets the definition of a major stationary source and is subject to evaluation and review under the provisions of the PSD regulation for all these pollutants. A PSD review involves the following six requirements:

1. Demonstration of the application of Best Available Control Technology (BACT).
2. Demonstration of compliance with each applicable emission limitation under Title 401 KAR Chapters 50 to 65 and each applicable emissions standard and standard of performance under 40 CFR 60, 61, and 63.
3. Air quality impact analysis.
4. Class I area impact analysis.
5. Projected growth analysis.
6. Analysis of the effects on soils, vegetation and visibility.

Furthermore, this source will also be subject to Title V and Title IV Phase II Acid Rain permitting. The Title V permitting procedures are contained in State Regulation 401 KAR 52:020, *Permits* and Federal Regulation, 40 CFR Part 70. The Title IV permitting procedures are within State Regulation 401 KAR 50:020, *Permits*, 401 KAR 52:060, *Acid Rain Permit*, and Federal Regulation 40 CFR part 76. This proposal represents the draft PSD/Title V permit and the draft Title IV Phase II Acid Rain permit. The preliminary determination is also provided as a statement of basis for the Title V permit. This review demonstrates that all regulatory requirements will be met and includes a draft permit that establishes the enforceability of all applicable requirements.

2. BACKGROUND

On March 01, 2001, the Division received a permit application to construct and operate pulverized coal fired boilers for electricity generation from Thoroughbred Generating Company, LLC. The application was logged administratively complete on April 23, 2001. A revised application was received on October 26, 2001. During the technical review process additional information was requested and responses received on the following dates:

INFORMATION SUBMITTAL TIMELINE
for the
THOROUGHBRED GENERATING STATION

Recipient	Date	Document Title	Received
KYDAQ	June 13, 2002	NAAQS and PSD Increment Compliance Analysis Demonstrating24-hour Protects 3-hour	June 14, 2002
KYDAQ/EPA R4	June 5, 2002	Emailed copies of information supplied to KYDAQ regarding May 14, 2002 meeting; CAM; and the SO2 NAAQS and PSD increment limit	June 5, 2002
KYDAQ	June 4, 2002	Hand delivered responses to May 14, 2002 meeting in Frankfort with KYDAQ, EPA R-IV, and TGC	June 5, 2002
KYDAQ	June 4, 2002	Hand delivered updated Cam plan per KYDAQ, EPA and TGC agreement	June 5, 2002
KYDAQ	June 4, 2002	Hand delivered analysis of an emission limitation for SO2 to protect the short-term NAAQS and Class II PSD increment	June 5, 2002
KYDAQ	June 4, 2002	Emailed responses to May 14, 2002 meeting in Frankfort with KYDAQ, EPA R-IV, and TGC	June 4, 2002
KYDAQ	June 4, 2002	Emailed updated Cam plan per KYDAQ, EPA and TGC agreement	June 4, 2002
KYDAQ	June 4, 2002	Emailed analysis of an emission limitation for SO2 to protect the short-term NAAQS and Class II PSD increment	June 4, 2002
KYDAQ	May 29, 2002	Addendum to October 2001 application (Paper copy) 1 Refined BACT; 2 Refined MACT; 3 CAM Plan; 4 Refined SO_2 Increment; 5 Refined CALPUFF 90, 92 & 96; 6 Dep Forms; 7 Site Location Map.	May 29, 2002
KYDAQ	May 28, 2002	Email copies of DEP 7007 Forms for ESP and WESP	May 28, 2002
KYDAQ	May 24, 2002	Mine Information (Paper copy)	May 28, 2002
KYDAQ	May 24, 2002	Response to NPS Bunyak Letter with Dr. Honaker Analysis (Paper copy)	May 28, 2002
KYDAQ	May 24, 2002	TGS NAAQS Compliance Demonstration	May 28, 2002
KYDAQ	May 24, 2002	Email mine information	May 24, 2002
KYDAQ	May 24, 2002	Email Response to NPS Bunyak Letter with Dr. Honaker Analysis	May 24, 2002

INFORMATION SUBMITTAL TIMELINE
for the
THOROUGHBRED GENERATING STATION

Recipient	Date	Document Title	Received
KYDAQ/EPA R4	May 14, 2002	Responses to Inquiries from KYDAQ, US EPA Region IV and Others on the TGS Draft Permit and Revisions	May 14, 2002
KYDAQ	May 10, 2002	Letter Addressing CAM with Respect to SO_2 and NO_x	May 10, 2002
KYDAQ	May 10, 2002	Responses to Inquiries from KYDAQ, US EPA Region IV and Others on the TGS Draft Permit	May 10, 2002
KYDAQ	April 24, 2002	Coal Washing Info	April 24, 2002
KYDAQ	April 17, 2002	Responses to Comments	April 17, 2002
KYDAQ	March 10, 2002	TGS Responses to EPA Region IV's February 26, 2002 comments on draft permit, Repeat of Information on CAM, MACT, BACT Modeling Control Equipment, Flow Diagrams, and Responses	March 10, 2002
KYDAQ	February 28, 2002	TGS Responses to EPA's December 21, 2001 comments on air permit and application	February 28, 2002
KYDAQ	February 21, 2002	Explanation of PM 20D Demonstration	February 25, 2002
KYDAQ	February 19, 2002	Additional Copies of CALPUFF Modeling Disks Public and Copyright	February 19, 2002
KYDAQ	February 15, 2002	Assertion of Confidentiality Modeling Input Files 90,92, & 96	February 18, 2002
KYDAQ	February 12, 2002	Increment Consumption Modeling Results for TGS	February 12, 2002
KYDAQ/EPA R4	February 4, 2002	Increment Consumption Modeling Methodology for Christian, Daviess, Ohio and Webster Counties	February 6, 2002
KYDAQ	February 6, 2002	Addendum to CALPUFF Modeling 90& 92/Confidential Request/Public and Copyright CDS	February 6, 2002
EPA-R4	February 5, 2002	Addendum to CALPUFF Modeling 90& 92/Public and Copyright CDS	February 5, 2002
NPS	February 5, 2002	Addendum to CALPUFF Modeling 90& 92/Public and Copyright CDS	February 5, 2002
KYDAQ/EPA R4	January 11, 2002	Letter Addressing Increment Consumption Modeling and Emails on 1-10-2002	January 11, 2002
KYDAQ	January 2, 2002	Case-By-Case MACT Supporting Information	February 2, 2002
KYDAQ	December 21, 2002	Case-By-Case MACT Determination	December 21, 2002
KYDAQ	December 12, 2001	Response to Comments Received from US EPA Region IV and US DOI. Included Information on Control Equipment and Flow Diagrams as Requested by EPA	December 13, 2001

INFORMATION SUBMITTAL TIMELINE
for the
THOROUGHBRED GENERATING STATION

Recipient	Date	Document Title	Received
KYDAQ	October 26, 2001	Revised PSD/Title V/Acid Rain Permit Application for Thoroughbred Generating Station	October 26, 2001
KYDAQ	October 9, 2001	Revised Class I CALPUFF Visibility Information (Information from meeting)	October 9, 2001
KYDAQ	October 1, 2001	Revised CALPUFF Class I Modeling Results	October 1, 2001
KYDAQ	September 6, 2001	Response Comments from the National Park Service on the Thoroughbred Generating Station PSD Construction Permit Application	
KYDAQ	February 28, 2001	PSD/Title V/Phase II Acid Rain Permit Application for Thoroughbred Generating Station	March 1, 2001

3. EMISSIONS ANALYSIS

The proposed Thoroughbred Generating Station will produce electricity as an independent power producer. The electricity generation operations will consist of: two (2) pulverized coal-fired boilers PCBs (nominally 750 MWe each) equipped with selective catalytic reduction (SCR); electrostatic precipatator (ESP); wet flue gas desulfurization (FGD); and a wet electrostatic precipitator (WESP). Additional processes at the facility will include a diesel fired auxiliary boiler (to operate 500 hrs or less per year); two diesel and one electric emergency fire-water pumps (to operate 500 hours or less per year for testing and emergencies); an emergency diesel fired generator (to operate 500 hours or less per year for testing and emergencies); coal and FGD handling facilities; two cooling towers; coal storage piles; ash handling facilities; and two (2) fuel oil storage tanks. Detailed descriptions of the plant processes and expected emissions at each emissions point and emissions unit are contained in the application, please see Volume I, Section 3, Section 4 and Volume II, Appendix A of the October 26th application respectively. In addition, hourly and annual emission rates and pollutant identification for each respective emission unit can be referenced from the application. Emissions were based on the maximum rated capacity of the plant, worst-case operating conditions, and 8760 hours per year after controls. The PCBs' annual emissions, as shown below in Table 3.1 and in Table 4.0-1 of the application, are calculated for worst-case conditions while operating at 100% load. Evaluations at 50% and 75% load were also performed.

Table 3.1 –Applicant Annual Emission Summary

POLLUTANTS	EMISSION RATE TONS PER YEAR
CARBON MONOXIDE (CO)	6,599
NITROGEN OXIDES (NO_x)	6,029
PARTICULATE MATTER (PM_{10})	1,328
SULFUR DIOXIDE (SO_2)	10,954
VOLATILE ORGANIC COMPOUNDS (VOC)	509
MERCURY (Hg)	0.21
BERYLLIUM (Be)	0.0615
FLUORIDES (AS HF)	10.34
SULFURIC ACID MIST (H_2SO_4)	326

4. REGULATORY REVIEW

This section presents a discussion on the air quality regulations applicable to this project in addition to the PSD requirements. In some cases the emission limit or technology standard based on these regulations may be superseded by the BACT requirements which are more stringent under PSD (see Section 5, Best Available Control Technology Review); however, any specific testing, monitoring, record keeping, and reporting requirements contained in these regulations will still have to be met by the source in addition to any requirements under PSD.

The following regulations will apply to the proposed plant (please see the application for a detailed description of the plant and specific processes/units within the plant):

A. New Source Performance Standards (NSPS)

The Clean Air Act of 1970 directed U.S. EPA to establish New Source Performance Standards, or NSPS, for specific industrial categories. There are three NSPS applicable requirements to the Thoroughbred project.

New Source Performance Standards for Steam Electric Generating Units

Under the NSPS directive, U.S.EPA developed 40 CFR Part 60, Subpart Da, for all new, modified, or reconstructed steam generating units with a maximum heat input capacity greater than 250 MMBTU/hour for which construction is commenced after September 18, 1978. The proposed PCBs will be subject to Subpart Da, since the PCBs will be constructed after September 18, 1978. The emission limits being proposed for the PCBs are much lower than the applicable standard for NOx, SO_2 and PM/PM_{10} emissions in Subpart Da. Therefore the NSPS requirements will be met.

New Source Performance Standards for Coal Preparation Plants

Subpart Y of 40 CFR part 60, Standards of Performance for Coal Preparation Plants, incorporated by reference in regulation 401 KAR 60:005, Section 3(1), requires coal processing facilities to comply with certain particulate standards. Activities regulated by this NSPS include crushing, screening, conveying, transferring and storage of coal. Emission points are subject to an opacity limitation of 20%. Proposed BACT emission limits for coal processing activities will meet all NSPS requirements.

New Source Performance Standards for Non-Metallic Mineral Processing Plants

40 CFR part 60 Subpart OOO, Standards of Performance for Non-Metallic Processing Plants, incorporated by reference in regulation 401 KAR 60:670, regulates particulate emissions from crushing, screening, milling, transferring and truck unloading of Non-Metallic Minerals. Operations enclosed in buildings are allowed zero fugitive emissions. Emissions vented through a stack are limited to 7% opacity and 0.05 gr/dcm. Conveyors and transfer points are allowed 10% fugitive visible emissions, while crushing operations are allowed 15% opacity if a capture system is not used. Trucks unloading into screening operations, hoppers or crushers are exempt from the particulate matter standard. The proposed BACT emission limits for non-metallic mineral processing will meet these NSPS requirements.

New Source Performance Standards for Industrial-Commercial-Institutional Steam Generating Units

Under the NSPS directive, U.S.EPA developed 40 CFR Part 60, Subpart Db, for all new, modified, or reconstructed steam generating units with a maximum heat input capacity greater than 100 MMBTU/hour for which construction is commenced after June 19, 1984. The proposed Auxiliary Boiler will be subject to Subpart Db, since it will be constructed after June 19, 1984. Proposed BACT emission limits for the auxiliary boiler will ensure these NSPS requirements are met.

B. State Requirements

The State of Kentucky has developed specific new source standards in 401 KAR 59:016 for new electric utility steam generating units. 401 KAR 59:016 standards apply to each electric utility steam generating unit built after September 19, 1978, that is capable of combusting more than 250 MMBTU/hr heat input of fossil fuel. Additionally, Kentucky has developed new source standards in 401 KAR 59:015 which apply to indirect heat exchangers built after the classification dates and that are capable of a heat input capacity greater than 1 MMBTU/hr. Regulation 401 KAR 59:015 does not apply to units subject to 401 KAR 59:016. The state's emission standards parallel the Federal NSPS standards therefore, the proposed facility will also be in compliance with Kentucky emission standards if it is in compliance with NSPS standards. Regulation 401 KAR 63:020, applies to Potentially hazardous matter or toxic substances

C. Maximum Achievable Control Technology Standards (MACT)

40 CFR 63, Subpart B, Requirements for Control Technology Determinations for Major Sources in Accordance With Clean Air Act Sections, Sections 112(g) and 112(j) ("Case by Case MACT")

Section 112(g) of the 1990 Clean Air Act Amendments (CAAA), requires certain new major sources of HAPs to implement maximum achievable control technology (MACT) standards. MACT standards are used to ensure a performance-based method for reducing toxic and HAP emissions. The control technology to be used to ensure maximum control is determined by establishing a MACT floor. The MACT floor for existing units is the average emission limitation achieved by the best performing 12% of existing sources. The floor for new sources can be no less stringent than the emission control achieved in practice by the best-controlled similar source.

Currently there are no finalized MACT standards for HAP emissions from oil and/or coal fired electric utility steam generating units. However, in a notice of regulatory finding released in December 2000, the USEPA indicated that the development of regulations under Section 112 of the Clean Air Act for HAP emissions from this industry is warranted. The USEPA further indicated that the proposed emission standards for HAP emissions from oil and/or coal fired electric utility steam generation units will be issued no later than December 2003 with promulgation of these standards no later than December 2004.

The applicant has submitted to the Division case-by-case a MACT determination for possible HAPs. Additional information received indicates that the control technologies being proposed at the facility will be equal to or better than any similar source. KYDAQ concurs with the applicant's determination. Based on the control technologies being used at the facility and the data provided in the USEPA documents the proposed control technology and emission limits will meet the control levels at other sources. According to the application the overall mercury removal from the facility is estimated to be greater than 80 percent with possible removals in excess of 90 percent. Similarly, other HAP emissions from the facility will be controlled by the combination of dry ESP, wet FGD and WESP. Based on the proposed control technologies and the reductions expected, the facility should meet the requirements for the best-controlled similar sources and therefore complies with all applicable MACT requirements.

Please see all relevant requirements for HAPs on case-by-case MACT in the permit.
Pursuant to 63.41 the permit will serve as the Notice of MACT approval.

D. Phase II Acid Rain Permits

Title IV of the Clean Air Act requires reductions in emissions of SO_2 and NO_x in an effort to reduce formation of acid rain. USEPA, in promulgating regulations in 40 CFR Part 72, requires the submittal of application forms (incorporated by reference in Regulation 401 KAR 52:060) no later than two years prior to commencing operations of a regulated unit. This source is required to apply for a Phase II Acid Rain permit. Under Phase II Acid Rain requirements, filing of a Title V application for a new source subject to the Acid Rain requirements requires the source to file the Phase II application at the same time. Additionally, part 75 requires continuous emission monitoring for NOx and sulfur dioxide. Proposed emission limits for NO_x and SO_2 are much lower than Title IV Acid Rain requirements. Therefore, Title IV requirements will be met.

E. CAM-Compliance Assurance Monitoring

Regulation 40 CFR 64.2 and 64.4 are applicable requirements for the source. Therefore, in accordance with 40 CFR 64, the applicant has submitted additional information on the monitoring plan for particulate matter (PM), particulate matter less than ten micrometers in diameter (PM_{10}), Hydrogen Fluoride (HF) and Sulfuric acid (H_2SO_4,). Sulfur dioxide ($S0_2$), and nitrogen oxides (NOx) will be monitored by Continuous Emissions Monitor (CEM), which will be used as the continuous compliance determination method to demonstrate BACT compliance, and to preclude applicability of Regulation 40 CFR 64. Pursuant to 401 KAR 52:020 the plan shall receive public notice to ensure federal enforceability.

<u>Monitoring Approach</u>

Applicable CAM Requirement	PM/PM_{10} limits	HF limits	H_2SO_4 limits
General Requirements	0.018 lb/MMBTU filterable particulates	0.000159 lb/MMBTU 30-day rolling average	0.00497 lb/MMBTU 30-day rolling average
	20% Opacity		
Monitoring Methods and Location	Initial Source Test & (1) installation of a COM at outlet of the dry ESP and monitoring of the WESP electrical field and other relevant parameters identified during initial testing* or (2) visual observation of plume from stack	SO_2 CEMs plus initial source test, coal sampling	SO_2 CEMs plus initial source test, coal sampling
Indicator Range	(1) Initial source testing to establish COM and equipment parameter indicator ranges, including the WESP electrical fields, as appropriate or (2) Initial source testing to establish compliance with the PM limit at 20% opacity. If opacity is perceived to exceed 20% during the qualitative visual observation, conduct a Method 9 observation	Initial source testing to establish correlation to SO_2 and coal quality, then establish SO_2 CEM and coal range appropriate	Initial source testing to establish correlation to SO_2 and coal quality, then establish SO_2 CEM and coal range appropriate
Data Collection Frequency	(1) Continuous COM and control device operating parameters or (2) daily observations	Continuous CEM, quarterly coal composites	Continuous CEM, quarterly coal composites

Averaging Period	(1)Opacity – 6 minute averages COM control device parameters – 3 hours or (2) Visible Emission Surveys – 1 minute; Method 9	30-day	30-day
Recordkeeping	COM data system records and control device parameters will be maintained for a period of 5 years or visible observation records and method 9 observations will be kept in a designated logbook and maintained for a period of 5 years.	Coal quality information will be kept in a designated log book, plus CEM data system records	Coal quality information will be kept in a designated log book, plus CEM data system records
QA/QC	COM will be maintained and operated in accordance with 401KAR 59:005 / 40CFR 60 Appendix B and/or other requirements as applicable, ESP/WESP monitored parameters will be maintained and operated in accordance with manufacturer recommendations; or records of method 9 certifications will be maintained	FGD/WESP will be maintained and operated in accordance with manufacturer recommendations	FGD/WESP will be maintained and operated in accordance with manufacturer recommendations

* 40 CFR 60, Subpart Da, allows the alternative location of COMS, in cases where the stack is considered to be wet (as the TGS stack will be upstream of the wet scrubber after the particulate control device). In the case of TGS, the particulate control consists of the dry ESP prior to the wet scrubber and a WESP after the wet scrubber. Therefore, COMS cannot be installed in TGS's wet stacks due to the inaccurate opacity readings. Hence, TGS proposes to install COMS at the outlets of the ESPs, and to identify appropriate PM operating parameters for the ESPs and WESPs (such as electrical field monitoring or operation or other parameters) within 180 days after initial source testing, with appropriate collection frequencies, recordkeeping, indicator ranges and QA/QC. In the alternative, TGS proposes to use periodic visible observations with requirements to use method 9 surveys as needed.

Monitoring Approach Justification

Particulate matter emissions are controlled by the ESP and WESP prior to discharge through wet stacks. The HF and H_2SO_4 emissions are controlled by the FGD and WESP prior to discharge to the stacks. The design collection efficiency of the PM_{10} control equipment is 99% or greater. The design removal efficiency for HF and H_2SO_4 control equipment is above 95% based on the SO_2 removal efficiency.

Rationale for Selection of Performance Indicator

The use of CEMs, provides continuous compliance results in units of the standard for the pollutant of interest and meets the criteria in 40 CFR Part 64.3 (d) (2) and is considered acceptable CAM. Therefore it may be used as a surrogate for HF and H_2SO_4 that behave similarly and are controlled by the same devices.

TGS is proposing a continuous opacity monitor (COM) at the location recommended by the control equipment vendor that would not cause corrosive, plugging or wet stack problems with long term operation of a COM, that location being immediately after the dry ESP. Since the dry ESP's, are the first PM control device (the second being the WESP), the COM data would be supplemented with appropriate equipment operating parametric monitoring for the WESP, with indicator ranges to be determined during initial stack testing of the entire control equipment sequence (SCR, ESP, FGD scrubber and WESP). Since the entire control system sequence may influence final PM emission rates and ultimate compliance with the proposed emission standard, the CAM Plan will be finalized upon completion of the stack testing program and submitted for approval within 180 days of completion of the initial stack testing.

In the event the above method is determined to be unachievable, TGS proposes as an alternative, that qualitative visual observation of the opacity of emissions from the stack will be performed on a daily basis and a log of the observations shall be maintained. If visible emissions from any stack are seen, then the opacity of emissions shall be determined by Reference Method 9 and an inspection of the control equipment for any necessary repairs shall be performed. Additionally, a Method 9 analysis shall be performed weekly and the results recorded in the same log.

Rationale for Selection of Indicator Range

PM CAM indicator ranges for the ESPs and WESPs will be established for parameters commonly monitored, since reliance solely on COMs after the ESPs may not provide complete compliance assurance. Additional PM control will be achieved by the WESPs. However, COMs are not appropriate at the outlet of each WESP, based on prior operating history of COMs in a wet stack environment. This proposed CAM Plan initially identifies monitoring of WESP electrical fields as the indicator. TGS may modify the proposed CAM Plan to use other or additional indicators pending results of initial source testing to establish the PM control efficiency effects of fluctuating coal quality, operation of the SCRs, FGDs and the ESPs and WESPs.

The use of the initial source test, coupled with coal analyses for the initial test and CEMs readings for SO_2 during the test would allow development of a correlation on HF and sulfuric acid mist to CEM measurement and coal quality. The use of coal sulfur content would be a direct indicator of expected sulfuric acid uncontrolled emissions, which would then be correlated to CEM SO_2 results to determine compliance. Also quarterly coal composite information will be used to predict fluoride emissions.

F. Additional Requirements

The owner is required to conduct a performance test within 60 days after achieving the maximum production rate at which the affected facilities will be operated but not later than 180 days after initial start-up of such facilities. Under the NSPS, indirect heat exchangers of greater than 250 MMBTU/hr heat input, firing coal derived fuels are required to be performance tested for pollutants to which the standard applies.

Subpart Da requires an initial performance test for particulates, sulfur dioxide and nitrogen oxides. 40 CFR 60 Subpart Da refers to 40 CFR 60.8 for testing requirements. The facility will perform an initial compliance test for particulates, sulfur dioxide and nitrogen oxides per Appendix A of 40 CFR 60.

The source will have a continuous emission monitor (CEMs) for SO_2, NO_x, CO and oxygen or CO_2, as well as, COMs for opacity monitoring on the PC boilers.

Compliance with 40 CFR 75 will constitute compliance for the appropriate monitoring, testing, reporting, and record keeping requirements of Subpart Da.

G. PSD Requirements

As stated earlier, Regulation 401 KAR 51:017 (40 CFR 52.21), Prevention of Significant Deterioration (PSD) of air quality, applies to the proposed plant. The facility will be located in Muhlenberg County, which is currently designated as "attainment" or "unclassified" for all ambient quality standards. Total plant wide potential emissions of all criteria pollutants including fugitive emissions are listed in Table 4.1.

TABLE 4.1 – Total Plant Wide Potential Emissions

Pollutant	PTE * (tons per year)	Significant Emission Rate ** (tons per year)
Nitrogen oxides (NO_x)	6,029	40
Carbon monoxide (CO)	6,599	100
Sulfur dioxide (SO_2)	10,954	40
Particulate (PM/PM_{10}	1,328	25
Volatile organic compounds (VOC)	509	40
Fluorides (as HF)	10.34	3
Mercury (Hg)	0.21	0.01
Beryllium (Br)	0.0615	0.0004
Sulfuric Acid Mist (H_2SO_4)	326	7

* PTE - Potential to emit, emissions for PCBs calculated with 8760 hours/year operation and worst case operating conditions, and include ancillary equipment.

** Significant emission rate as given in Regulation 401 KAR 51:017, Section 22.

As seen in the preceding table, the plant will be a major source for all of the pollutants listed. The PSD review applies to every pollutant that the proposed plant will emit in significant quantities, i.e., in amounts that will exceed the respective significant net emission rate. In addition, the plant will be subject to PSD review for sulfuric acid mist, mercury, beryllium, fluorides as HF, VOCs, nitrogen oxides, carbon monoxide, sulfur dioxide, and PM/PM_{10}. For each of these pollutants, the applicant has performed a best available control technology (BACT) demonstration and an ambient air quality analysis. Each of these components of the PSD review process have been discussed in detail in the following sections.

5. BEST AVAILABLE CONTROL TECHNOLOGY REVIEW

Pursuant to Regulation 401 KAR 51:017, Section 9(1) and (2), a major stationary source subject to a PSD review shall meet the following requirements:

(a) The proposed source shall apply the best available control technology (BACT) for each pollutant that it will have the potential to emit in significant amounts.

(b) The proposed source shall meet each applicable emissions limitation under Title 401, KAR 50 to 65, and each applicable emission standard and standard of performance under 40 CFR 60, 61, and 63.

The proposed source will be a major source resulting in emissions of sulfuric acid mist, beryllium, mercury, fluorides as HF, VOCs, nitrogen oxides, carbon monoxide, sulfur dioxide, and PM/PM_{10} that exceed the corresponding PSD net significant emission amounts. Therefore, each of these pollutants was subjected to a BACT review.

Thoroughbred Generating Station has presented, in the permit application, a study of the best available control technology for each pollutant and each emissions unit at the proposed source. The Division has reviewed the proposed control technologies in conjunction with information available in the USEPA's RACT/BACT/LAER Clearinghouse (RBLC) database and other similar sources. A summary of the control technology determined to be the best available control technology for each pollutant and each emissions unit is presented in Table 5.1.

TABLE 5.1 – BACT Summary for PC Boilers

EIS No.	Emissions Unit/Process	Pollutant	Best Available Control Technology	Emission Standard
01, 02	Pulverized Coal Fired Utility Boilers Operation limitation: None The emission control equipment and emission limits proposed will ensure compliance with all future MACT requirements.	NO_X	Proper Boiler Design, Low NO_x Burners & SCR Visibility Limit	0.08lb/ MMBTU
		CO	Proper Boiler Design & Operation	0.1 lb/MM BTU
		SO_2	Proper Boiler Design, WFGD & WESP Visibility Limit	0.167 lb/MM BTU
		PM/PM_{10}	ESP/WESP	0.018 lb/MM BTU
		VOCs	Proper Boiler Design and operation	0.0072 lb/MM BTU
		Beryllium Mercury	ESP, WESP, WFGD	$9.44e^{-7}$ lb/MM BTU $3.21e^{-6}$ lb/MM BTU
		Fluorides as HF	Proper Boiler Design & Control Technology, WET FGD Scrubbing and WESP	$1.59e^{-4}$ lb/MM BTU
		Sulfuric Acid Mist	Proper Boiler Design & Control Technology, ESP, FGD, and WESP Visibility Limit	0.00497lb/MM BTU

The permittee submitted a top-down Best Available Control Technology (BACT) analysis following the U.S. EPA guidance, "New Source Review Workshop Manual" (U.S. EPA, October 1990). The key steps involved with the top-down BACT process are as follows:

1. Identify all control technologies
2. Eliminate technically infeasible options
3. Rank remaining control technologies by control effectiveness
4. Evaluate most effective controls considering economic, environmental, and energy impacts, and document results.
5. Select BACT.

A. BACT for Pulverized Coal (PCB) Fired Boilers

The following section summarizes the BACT determinations for criteria pollutants from the proposed facility. Using the top-down approach, the applicant selected various technologies for analysis of technical and practical feasibility, and then applied economic cost-effectiveness analyses where the top ranked technology was not selected. Table 4.0-4 from the application is provided below as Table 5.2, and lists various technologies considered by the applicant in its BACT evaluation.

TABLE 5.2 - Ranking of Control Technologies by Effectiveness

Pollutant	**Control Technology**	**Add-on Control Efficiency (%)**	**BACT Limit**
PM/PM_{10}*	Electrostatic Precipitator (ESP)	99.9‡	0.018 lb/MMBTU
	Wet Scrubber	90.0‡	
	Cyclone	90.0‡	
SO_2	Wet Scrubbers/ Wet ESP	90+	0.167 lb/MMBTU
Sulfuric Acid Mist	Proper Boiler Design control technology, ESP, FGD, WESP	90+	0.00497 lb/MMBTU
NOx	Selective Catalytic Reduction (SCR)	60-90	0.08 lb/MMBTU
	Low NO_x Burner, Startup Operations	15-30**	
	Proper Boiler Design and Operation		
CO	Thermal Oxidation	95‡	0.10 lb/MMBTU
	Catalytic Incineration	90-95‡	
	Excess Air	75‡	
	Proper Boiler Design and Operation		
VOCs	Proper Boiler Design and Operation		0.0072lb/MMBTU
Beryllium	ESP, WESP, WFGD	99.9‡	
Mercury	Scrubbing and Baghouse		
HF	Proper Boiler design and control Technology, ESP, FGD, WESP		0.000159 lb/MMBTU

‡Cooper, C.D. and F.C. Alley, *AIR POLLUTION CONTROL: A Design Approach*, Waveland Press, 1986.

**Alternative Control Technologies Document NOx Emissions from Utility Boilers, US EPA-453/R-94-023, 1994

NOx

Control methods for NO_x can be divided into two types of control technologies: post-combustion controls and combustion controls. Post-combustion NO_x control removes NO_x from the exhaust gases of the boiler. Combustion NO_x control reduces the amount of NO_x that is generated during combustion.

The applicant is proposing low NO_x burners to address the combustion generating part of the analysis. Low NO_x burners have been accepted as BACT for combustion control technology consistently for similar sources in the past. Post-combustion NO_x control techniques were also considered to further control NOx.

The applicant has elected to utilize selective catalytic reduction (SCR) in conjunction with low NO_X burners to reduce NOx emissions to levels below those required by recent EPA proposed regulations regarding ozone, and to meet the most stringent NO_x emission limitation in the RBLC.

SCR and low NO_X burners are supported by recent determinations in the RBLC database for PC boilers and other similar applications currently being reviewed in other regulatory agencies. In consideration of RBLC, the applicant is proposing that the NO_x emission limitation be set at 0.08 lb/MM BTU heat input on a 30 day rolling average, which also address visibility concerns expressed by the National Parks Service at Mammoth Cave.

CO

Carbon monoxide is formed as a result of incomplete combustion of fuel. For carbon monoxide control, the permittee evaluated the available control technologies, which are: high temperature oxidation, catalytic oxidation and the front-end technique of good combustion control. The most stringent CO control level available for PCBs would be achieved with the use of a high temperature oxidation system added at the exhaust of the baghouses, which can remove approximately 95 percent of CO in the flue gas. Proper boiler design and operation is BACT for CO emissions. The CO emissions shall not exceed 0.10 lbs/MMBTU from each unit based on a thirty (30) day rolling average.

The Division has reviewed the EPA BACT/RACT/LAER Clearinghouse for PC boilers and the overwhelming majority of determinations specify good combustion practice; good combustion control and operation; proper design; and in some cases no controls.

There are environmental impacts associated with the use of a catalytic oxidation system on a PC boiler due to the oxidation of SO_2 to SO_3. The SO_3 can react with water or ambient ammonia in the exhaust and form sulfuric acid or ammonia sulfates. There is also generation of hazardous waste from the spent catalyst.

The economic analyses provided for the CO thermal and catalytic oxidation options provided by the applicant are shown in Section 4 of the permit application additional information submitted on May 10, 2002. The Division has reviewed and accepted cost data provided by the applicant. This information indicates the total capital investment costs, annualized costs, and overall cost effectiveness for CO emissions calculated by the permittee. Table 5.3 summarizes the results of the overall cost effectiveness of CO removal for each PCB:

Table 5.3 – CO Removal Cost Effectiveness

PCB Model	Overall Cost Effectiveness ($/ton)
Thermal Oxidation	13,899
Catalytic Oxidation	9,795

The Division has determined that the overall cost effectiveness numbers indicate that the application of high temperature or catalytic oxidation for CO is not economically feasible.

Considering the potential environmental and energy impacts associated with extended startup times and the economic impact of oxidation catalyst technology, the Division consider a proper boiler design and operation as BACT for CO emissions. CO formation is minimized when the boiler temperature and excess oxygen availability is adequate for complete combustion. Minimization of the CO emitted is in the economical best interest of the boiler operator as CO represents unutilized energy exiting the process. No incremental costs are associated with this option. In Section 4 of the application, the applicant, in discussing NO_x control, noted that CO emission rates are identified as a potential factor, which affects NO_x emissions inverse proportionally (i.e., lower CO tends to produce higher $NO_{x.}$

<u>SO_2</u>

The applicant considered coal washing and several potential Flue Gas Desulfurization systems and acid gas control technologies for the proposed project. These technologies are listed in Table 4.2-1 *SO_2 Emission Control Options* of the revised application. All of the control technologies are capable of removal efficiencies in excess of 90%, however not all technologies are capable of effectively reducing the amount of acid gases emitted. The source is proposing revised BACT emission limit of 0.167 lbs/MMBTU with a list of possible control technologies for SO_2 and a H_2SO_4 mist emission limit of 0.00497 lbs/MMBTU based on a 30 day rolling average. In addition, the source is identifying a maximum average emission rate of 0.45 lbs/MMBTU over a 24-hour block average that would be protective of the SO_2 24-hour National Ambient Air Quality Standards (NAAQS) and Class II increment of 91 ug/m^3.

The applicant performed additional analysis of available technologies, which would result in further reductions of SO_2 and acid gas emissions. It was determined that a combination of two technologies would reduce emission levels to ensure negligible change in visibility at the Mammoth Cave National Park and Class I Area. The technologies included wet limestone scrubbing, which will effectively control SO_2 and other pollutant emissions, and wet electrostatic precipitation, which will reduce HAP and acid gas emissions including HF and H_2SO_4.

The applicant also submitted analysis on coal washing as a method of reducing SO_2 emissions. Based on the information provided the Division concurs that the adverse environmental, energy, and economic impacts are unacceptable, therefore coal washing is not considered BACT for this facility.

PM/PM_{10}

Particulate matter emission from the PC boilers are primarily the result of ash content and other contaminants in the fuel. There are several control technologies for removing particulates from a gas stream but a baghouse and electrostatic precipitator (ESP) have the highest control efficiency of any of the particulate matter control options, and therefore, according to the "top-down" approach, must be considered first.

Baghouse:

A baghouse removes pollutants and condensed metals (beryllium, lead and mercury) from the exhaust gas by drawing the dust-laden air and condensables through a bank of filter tubes suspended in a housing. A filter "cake", composed of the removed particulate, builds up on the "dirty" side of the bag. Periodically, the cake is removed through physical mechanisms (e.g., a blast of compressed air from the "clean" side of the bag, shaking the bags, etc.), which cause the cake to fall. The dust is then collected in a hopper and eventually removed.

Electrostatic Precipitator (ESP):

Electrostatic Precipitators remove aerosol and particulate matter from exhaust gas streams by means of electrostatic attraction. Particles in the gas stream are negatively charged by discharge electrodes located in the ESP. Once the particles are negatively charged they migrate toward the grounded collection plates in the ESP, which have been positively charged. The particulate continues to accumulate on the collection plate until it is removed. The particulate is removed from the plates either by rapping or spraying. It is then collected in a hopper for disposal. ESPs have the ability to handle large gas streams and high particulate loading with very few complications and restrictions, as opposed to baghouses. While a baghouse and ESP are capable of similar removal efficiencies the ESP has a much broader operating range and can be utilized at higher temperature and pressure conditions, as well as, with wet or dry gas streams.

Wet Electrostatic Precipitator (WESP):

Wet electrostatic precipitators operate in much the same way as a dry or standard ESP; charging, collecting and finally cleaning. It is the cleaning step that is different. Cleaning is performed by washing the collection surfaces with water, in place of the usual mechanical means such as rapping of the collection plates. The delivery of the liquid or water can be made by a series of spray nozzles located in the control device or by condensing moisture from the flue gas on the collection surfaces. WESPs are able to control a larger variety of pollutants than an ESP can alone. WESPs are significantly better at controlling acid droplets and SO_3 gases. This has been well supported by installations at acid production plants and other industrial sources that have highly acidic exhaust streams. Higher levels of SO_3 in the exhaust gas actually greatly improve the collection efficiency of the WESP by reducing the electrical dust resistance. WESPs are also very effective in reducing re-entrainment of particles due to the constant cleaning of the collection surfaces by liquid. Additionally, WESPs can operate under much higher electrical power than ESPs, therefore enabling much greater reductions in sub micron particulates.

According to information supplied in the application when used in conjunction with wet flue gas desulfurization, WESPs are very effective in reducing SO_3, metals and other sub micron particulates. WESPs are discussed further in the section on SO_2 and acid gas controls.

The applicant has selected a electrostatic precipitator (ESP) and Wet electrostatic precipitator (WESP) as BACT for PM/PM_{10} , ESP, WFGD & WESP for mercury, beryllium, and other metals for the PC boilers. The current market information and other sources in the RBLC and the control technology being proposed for the PC Boilers PM/PM_{10} technology in conjunction with a PM/PM_{10} BACT, sets emission limits of 0.018 lb/MMBTU based on a three (3) hour average.

Control of Non-Criteria Pollutants

The combustion of coal may release trace amounts of a number of non-criteria pollutants. Three of the PSD regulated pollutants (mercury, beryllium, and sulfuric acid mist) require BACT analysis as defined by EPA. For all of these pollutants the RBLC database and other recently issued permits have indicated best available control technology is a baghouse control, FGD and proper boiler design and operation.

The BACT for metals, acid gases and other non-criteria pollutants is an ESP in combination with a flue gas desulfurization unit and proper design and operation of the boilers and system. However, due to the concerns expressed with regards to the possible visibility change at Mammoth Cave National Park, the applicant has agreed to install a electrostatic precipitator (ESP), wet Flue Gas desulfurization (WFGD)and wet electrostatic precipitator (WESP), which will further reduce the emissions of non-criteria pollutants such as acid gases (see prior section related to acid gases).

B. PM/PM_{10}-Material Handling

In the case of limestone, coal, and ash handling equipment, bin vent fabric filters and baghouses constitute BACT. This includes the emission from the silos, mills, crushers, and other devices. With respect to the conveyors and transfers, enclosure and coverings in addition to filter controls is deemed to be BACT for particulates. These types of controls are consistent with similar types of sources and equipment found in the RBLC and other recently issued permits.

C. PM/PM_{10}-Cooling Towers

Particulate emissions from the cooling towers in the form of drift shall be controlled by Drift Eliminators. The applicant has proposed 0.002% drift eliminators to control the emission of PM/PM_{10} from the cooling towers. Based on the information provided and the design of the system the Division agrees that the proposed 0.002% drift eliminators constitute BACT for particulate control from the cooling towers.

D. Auxiliary Boiler

The auxiliary boiler will be a 300 MMBTU/hr unit. The boiler will minimize emissions by utilizing low NO_x burners and firing low sulfur diesel fuel. The boiler will be used for the startup of the first boiler and operate on a limited basis. The Division agrees that the proposed design and operation of the boiler must be included in the BACT analysis and hour of operation for the boiler capped at 500 hours per year or less.

E. Fire Water Pumps

The applicant has proposed to install two 265hp fire pumps for emergencies. The Division agrees that the use of low sulfur diesel fuel and limiting operation of the pumps to 500 hours or less per year constitutes BACT for fire pumps.

F. Emergency Diesel Generator

Similar to the firewater pumps the applicant has proposed to install a 2.25 MW generator for emergency use. The Division agrees that the use of low sulfur diesel fuel and limiting the operation of the generator to 500 hours or less per year constitutes BACT.

G. Source Emission Units/Applicable Regulations

The following table identifies and describes each emissions unit, such as process units and control devices.

Table 1. Source Emission Units

Emissions Units		Air Pollution Control Devices	
ID. No.	**Description**	**ID. No.**	**Description**
01-02	7446 MM Btu/hr Pulverized Coal Fired Unit (each)-Steam Generating Combined Cycle; #2 Fuel as startup and stabilization	None	Equipped with SCR,ESP,WESP & WFGD
03	300 MM Btu/hr Auxiliary Boiler –Low sulfur diesel fired	None	None
04	Coal Handling Systems	MP01-MP12	Enclosure/Baghouse/Bin Vents/Filters
05	Coal Handling Systems	MP01-MP04	Partial Enclosure/Low Pressure Drop/Telescopic Chute
06	Coal Piles	MP01-MP05	Compaction/Suppressants
07	FGD Reagent Prep Handling	MP01-MP06	Enclosures/Filters
08	FGD Reagent Prep Handling-Fugitives	MP01-MP06	Compaction/Partial Enclosures/Filters
09	Fly Ash Handling System	None	Filters
10-11	Two Cooling Towers	None	0.002% Drift Eliminators

The steam electric generator, boiler, coal handling etc. are considered separate emissions units because they are individual activities that emit or have the potential to emit regulated air pollutants. Emissions unit means any part or activity of a stationary source that emits or has the potential to emit any regulated air pollutant or any pollutant listed under section 112(b) of the Act. This term is not meant to alter or affect the definition of the term "unit" for purposes of Title IV of the Act [40 C.F.R. § 70.2]. However, similar emissions units were combined in this permit into one emissions unit ID to simplify the permit. These emissions units have the same applicable requirements.

Insignificant Emission Units

Pursuant to 401 KAR 52:020, Section 6 allows sources to separately list in the permit application emissions units or activities that qualify as "insignificant" based on potential emissions. The insignificant emissions unit has the potential to emit below 5 tons/year for all regulated air pollutants and/or ½ ton per year for combined HAPs (Hazardous Air Pollutants). These units that that qualify as "insignificant" are in no way exempt from compliance demonstration and applicable requirements or any other requirements of the PSD/Title V permit. The following table describes each insignificant emissions unit located at the source.

Table 2. Insignificant Emission Units

Insignificant Emissions Units Description/Applicable Regulation
3, 265 Hp (500 hr/yr) Water Pumps (2) Diesel Fired (1) Electric – None
Maintenance Shop Activities –None
Fuel Oil Storage Tanks – 401 KAR 59:050
Miscellaneous Water Storage Tanks – None
FGD Solid Waste By-product Handling and Long-term Storage – None
2.25 MW (500 hr/yr) Diesel Fired emergency Generator – None
Ammonia tanks – 401 KAR 68

III. APPLICABLE REQUIREMENTS

Table 4. The following table lists the emissions units and their applicable requirements.

Emissions Unit ID	Pollutant	Emission Limitation / Operational Restrictions	Applicable Requirements	Monitoring		Compliance / Testing
				Record keeping	Reporting	
01-02 1500 MW 750 each Primary Fuel: coal 40 CFR 60, Subpart Da 40 CFR 63, Subpart B 40 CFR 64 40 CFR 75 & 76 401 KAR 51:017 401 KAR 59:016	PM	0.018 lb/MMBTU based on a 3-hour average	401 KAR 59:016, Section 3(1)b and 51:017	401 KAR 59:005 Section3(2) & Section (4)	401 KAR 59:005 Section3(3), 401 KAR 59:016 Sections 4, 7 & 9, Part 60 requirements	Initial and annual performance testing/ EPA Reference Methods 5, 9, 201 or 201A, & 202
	SO2	0.167 lb/MMBTU based on a 30-hour average 0.45 lb/MMBTU based on a 24 hr block average	401 KAR 59:016 Section 4(1), and 51:017	Continuous Emissions Monitoring	Part 60 & 75 requirements and reports for all required monitoring	Initial Performance Testing using CEMs
	NOx	0.08 lb/MMBTU based on a 30 day average	401 KAR 59:016 Section 4(1), and 51:017	Continuous Emissions Monitoring	Part 60 & 75 requirements and reports for all required monitoring	Initial Performance Testing using CEMs
	CO	0.10 lb/MMBTU based on a 30 day average	401 KAR 51:017	Continuous Emissions Monitoring	Reports of all required monitoring	Initial Performance Testing using CEMs
	VOC	0.0072 lb/MMBTU based on a 30-day average	401 KAR 51:017	NA	Reports of all required monitoring	Initial and annual Performance Tests/EPA reference methods 18 or 25

Emissions Unit ID	Pollutant	Emission Limitation / Operational Restrictions	Applicable Requirements	Monitoring		Compliance / Testing
				Record keeping	Reporting	
	HF	0.000159 lb/MMBTU based on a 30-day average	401 KAR 51:017	SO2 CEMs, Use SO2 emissions as surrogate for HF emissions	Reports of all required monitoring	
	Be	0.000000944 lb/MMBTU based on a quarterly average	401 KAR 51:017	SO2 CEMs, Use SO2 emissions as surrogate for Be emissions	Reports of all required monitoring	
	Acid Mist	0.00497 lb/MMBTU based on a 30-day average	401 KAR 51:017	SO2 CEMs, Use SO2 emissions as surrogate for H2SO4 emissions	Part 60 & 75 requirements and reports for all required monitoring	
	Hg	0.00000321 lb/MMBTU based on a quarterly average	401 KAR 59:016 Section 4(1), and 51:017	NA	Reports of all required monitoring	Initial Performance Tests/EPA reference method 29
	Pb	0.00000386 lb/MMBTU based on a quarterly average	401 KAR 51:017	NA	Reports of all required monitoring	Initial and annual performance tests/EPA Methods 12 or 29
03 Auxiliary Boiler	PM	0.06 lb/MMBTU based on a 3-hour average	401 KAR 59:015, Section 4(1)b	401 KAR 59:005 Section3(2) & Section (4)	401 KAR 59:005 Section3(3), 401 KAR 59:016 Sections 4, 7 & 9, Part 60 requirements	Initial and annual performance testing/ EPA Reference Methods 5, 9, 201 or 201A, & 202

Emissions Unit ID	Pollutant	Emission Limitation / Operational Restrictions	Applicable Requirements	Monitoring		Compliance / Testing
				Record keeping	Reporting	
	NOx	0.12 lb/MMBTU based on a 3-hour average	401 KAR 59:016 Section 4(1), and 51:017	Continuous Emissions Monitoring	Part 60 & 75 requirements and reports for all required monitoring	
	CO	0.06 lb/MMBTU based on a 30 day average	401 KAR 51:017	Continuous Emissions Monitoring	Reports of all required monitoring	
	VOC	0.03 lb/MMBTU as a 30 day average	401 KAR 51:017	NA	Reports of all required monitoring	
	SO2	0.05 lb/MMBTU based on a 3-hour average	401 KAR 59:015 Section 5(1)	Continuous Emissions Monitoring	Part 60 & 75 requirements and reports for all required monitoring	Initial Performance Testing using CEMs
04 Coal Handling Systems	PM	40 CFR 60.252	Standards of Performance for Coal Preparation Plants, 40 CFR 60, Subpart Y	Maintain Records of Coal received and Processed	50:055 Section 1, 52:020 Section 21 & 22	Method 9
05 Coal Handling System	PM	401 KAR 63:010, Section 3	401 KAR 63:010 & 51:017	Maintain Records of Coal received and Processed	50:055 Section 1, 52:020 Section 21 & 22	Method 9
06 Coal Piles	PM	None	401 KAR 63:010	Maintain Records of Coal received and Processed	50:055 Section 1, 52:020 Section 21 & 22	Method 9

Emissions Unit ID	Pollutant	Emission Limitation / Operational Restrictions	Applicable Requirements	Monitoring		Compliance / Testing
				Record keeping	Reporting	
07 FGD Reagent Prep Handling	PM	401 KAR 51:017, 40 CFR 60.672(a), 0.05 gr/dscm, shall not exhibit greater than 7% opacity	40 CFR 60, Subpart OOO, standards of Performance for Nonmetallic Mineral Processing Plants, 401 KAR 51:017	40 CFR 60:676	40 CFR 60:672	Method 9
08 FGD reagent Prep Handling –Fugitives	PM	None	401 KAR 63:010	Maintain Records of Coal received and Processed	50:055 Section 1, 52:020 Section 21 & 22	Method 9
09 Fly Ash Handling System	PM	401 KAR 59:010, Opacity <20%	401 KAR 51:017 & 59:010, New Process Operations	Maintain Records of Ash Processed	50:055 Section 1, 52:020 Section 21 & 22	Method 9
10-11 Cooling Towers	PM	401 KAR 63:010, Section 3	401 KAR 63:010 & 51:017	Maintain Records of Maximum pumping capacity and total liquid drift	50:055 Section 1, 52:020 Section 21 & 22	Monthly measurements of total dissolved solids content of circulating water

6. AIR QUALITY IMPACT ANALYSIS

Pursuant to Regulation 401 KAR 51:017, Section 12, an application for a PSD permit shall contain an analysis of ambient air quality impacts, in the area that the proposed facility will affect, for each pollutant that it will have the potential to emit in significant amounts as defined in Section 22 of the same regulation. The purpose of this analysis shall be to demonstrate that allowable emissions from the proposed source will not cause or contribute to air pollution in violation of:

(1) A national ambient air quality standard in an air quality control region; or
(2) An applicable maximum allowable increase over the baseline concentration in an area.

The proposed facility will have potential emissions in excess of the significant net emission rates for nitrogen oxides, PM/PM_{10}, sulfur dioxide, VOCs, fluorides as HF, beryllium, mercury, sulfuric acid mist and carbon monoxide.

A. Modeling Methodology

The application for the proposed source contains ISCST3 air dispersion modeling analysis for criteria and non-criteria pollutants (nitrogen oxides, PM/PM_{10}, sulfur dioxide, fluorides as HF, beryllium, mercury, sulfuric acid mist and carbon monoxide) to determine the maximum ambient concentrations attributable to the proposed plant for each of these pollutants for comparison with:

1. The significant impact levels (SIL) found in 40 CFR 51.165 (b)(2).
2. The Significant Air Quality Impact levels (SAI) found in Regulation 401 KAR 51:017, Section 24.
3. The PSD Class I and Class II increments found in Regulation 401 KAR 51:017, Section 23.
4. The National Ambient Air Quality Standards (NAAQS) found in Regulation 401 KAR 53:010, Ambient air quality standards.

All applicable ambient air quality concentration values are presented in Table 6.1. Based on U.S. EPA procedures, if the maximum predicted impacts for any pollutant are found to be below the SILs, then it is assumed that the proposed facility cannot cause or contribute to a violation of the PSD pollutant increments or the national ambient air quality standards (NAAQS). Therefore, no further modeling would be required for such a pollutant. The applicant may also be exempted from the ambient monitoring data requirements if the impacts are below the significant monitoring concentrations or SAI. The SAI levels determine if the applicant will be required to perform pre-construction monitoring. If the modeled impacts equal or exceed the SAI levels, pre-construction monitoring may be required. As shown in the application, the SAI levels were exceeded for the 3-hour; 24-hour; and annual modeled impacts. However, if existing air quality data is available that is representative of the air quality area in question an exemption may be granted. The applicant requested that data from the TVA Paradise monitors be accepted as representative of the area. The Division determined the location of the monitor; quality of the data; and the data's collection time frame all met the requirements listed in the NSR guidance manual and issued a letter of approval on September 22, 2000. Therefore, the applicant is exempted from the pre-construction ambient monitoring data requirements for sulfur dioxide.

TABLE 6.1 – Ambient Air Quality Concentration Values

Pollutant	**Averaging Period**	**SIL** ($\mu g/m^3$)	**SAI** ($\mu g/m^3$)	**PSD Class II Increments** ($\mu g/m^3$)	**NAAQS** ($\mu g/m^3$)
NO_x	Annual	1	14	25	100
PM_{10}	Annual 24-hour	1 5	NA 10	17 30	50 150
SO_2	Annual 24-hour 3-hour	1 5 25	NA 13 NA	20 91 512	80 365 1300
CO	8-hour 1-hour	500 2000	575 NA	NA NA	10000 40000

The permittee used the Industrial Source Complex Short Term model (ISCST3, Version *00101*, EPA, 1999) in the analysis. The ISCST3 model fulfills the requirements of Supplement C of the Guideline on Air Quality Models (Appendix W to 40 CFR 51). All of the parameters used in the modeling analysis for each pollutant appear satisfactory and consistent with the prescribed usage for this model. Per EPA guidance, the ISCST3 model was run with the regulatory default option in a sequential hourly mode using five years of meteorological data. Surface data and concurrent upper air data used were based on weather observations taken at the National Weather Service (NWS) station at the Paducah, Kentucky and Nashville, Tennessee respectively from 1985 to 1987 and 1990 to 1991.

With respect to the Class I modeling the applicant used the CALPUFF model with refined inputs to better predict possible impacts for the particular region in question. Detailed documentation of the modeling inputs and the techniques used are provided in Volume II, Appendix E of the application.

In consultation with the Federal Land Manager (FLM) and the National Park Service (NPS) the permittee has considered two more years of modeling, using 1992 and 1996 MM5 data with the concurrent surface, upper air, and precipitation data.

B. Modeling results - Class II Area Impacts

The proposed facility will be located in Muhlenberg County, a Class II area. The applicant modeled the impact of the emissions from the proposed facilities on the ambient air quality and the results of the modeled impacts on the Class II area have been presented in Table 6.2.

The modeling results show that the maximum impacts from the proposed facility for NO_x and CO are less than the EPA prescribed significant ambient impact levels (SIL) and no further analysis are required. However, the 24-hr and annual PM/PM_{10} impacts and the 3-hour; 24-hour; and annual sulfur dioxide impacts all exceeded the prescribed SILs. Therefore, refined modeling was performed for PM/PM_{10} and sulfur dioxide, by including all existing major sources within 100 km of the significant impact area for particulate and sulfur dioxide emissions. The refined modeling required for NAAQs and PSD Increment analysis is presented in Table 6.3. Modeling concentrations all were significantly lower than the NAAQS and PSD Increments allowed. However, a block maximum average emission rate over 24 hour period to protect the NAAQS and the Class II PSD increments has been set at 0.45 lbs/MMBTU based on statistical analysis.
Detailed descriptions of the modeling inputs and results are in Volume I, Section 6 and 7 of the application.

TABLE 6.2 – Applicants Modeled Predicted Impacts

Pollutant	Averaging Period	SIL ($\mu g/m^3$)	SAI ($\mu g/m^3$)	Max Impact of Emission ($\mu g/m^3$)	SIA (km)	Preconstruction Monitoring Required
NO_2	Annual	1	14	0.697		No
PM_{10}	Annual 24-hour	1 5	NA 10	1.69 8.86	2.5	NA No
SO_2	Annual 24-hour 3-hour	1 5 25	NA 13 NA	1.57 27.76 112.40	50	NA Exempt NA
CO	8-hour 1-hour	500 2000	575 NA	39.12 168.94		No NA
Beryllium	24-hour	NA	0.001	0.00088		No
Mercury	241-hour	NA	0.25	0.00285		No

TABLE 6.3 – Refined Modeling Results

Pollutant	Averaging Period	Class II PSD Increment ($\mu g/m^3$)	Applicant's Class II Increment Consumption[3] ($\mu g/m^3$)	NAAQs ($\mu g/m^3$)	Source Plus Other Sources Modeling Results ($\mu g/m^3$)	Source Plus Background Modeling Results ($\mu g/m^3$)
PM_{10}	Annual[1] 24-hour	17 30	1.69 8.86	50 150	1.97 13.17	27.69 75.17
SO_2	Annual[1] 24-hour 3-hour	20 91 512	1.57 27.76 112.40	80 365 1300	28.67 186.76 779.37	17.29 143.33 504.55
NO_x	Annual[2]	25	0.697	100	NA	NA

1. Annual geometric mean
2. Annual arithmetic mean
3. Increment consumption based on high-second-high

C. Modeling Results - Class I Area Impacts

The nearest federally designated Class I area to the project site is Mammoth Cave National Park. The nearest park boundary is approximately 74 km to the East-Southeast of the proposed facility and was analyzed by the applicant using the CALPUFF model at the request of the FLM and the Division. Results of this modeling are presented in Volume I, Section 8 of the application. Table 6.4 lists the modeled increment consumption for the proposed source and illustrates no Class I increments will be exceeded. Additional information regarding the Class I modeling is presented in Volume I, Section 8 and Volume II, Appendix E of the application.

Table 6.4 – Modeled Class I increment Consumption

Pollutant	**Averaging Period**	**Class I Increment** ($\mu g/m^3$)	**Source Class I Increment Consumption** ($\mu g/m^3$)
NO_x	Annual	2.5	0.018
PM_{10}	Annual 24-hour	4 8	0.016 0.137
SO_2	Annual 24-hour 3-hour	2 25 5	0.142 1.16 4.37
CO	8-hour 1-hour	500 2000	Not Required, less than Significant Level

Calpuff modeling was submitted with the application, however, on February 6, 2002, the Division received a revised air quality analysis for the TGS. The analysis identified an error in the previous analysis that tended to over-estimate potential impacts. The NPS performed independent visibility analyses that replicated and expanded upon the TGS modeling. The results of the NPS independent analysis concluded that TGS alone could cause a change in visibility in excess of 5% at Mammoth Cave National Park on 2 days during the 3 years modeled (maximum of 7.47% in 1996). In addition the NPS has conducted a cumulative visibility analyses modeling TGS with 58 SO2 PSD sources, using same fine and coarse grid that TGS used in its visibility and increment analysis. The maximum visibility impact of all these sources at Mammoth Cave National Park is 15.75 % (1996) of which 7.75% is attributable to TGS alone. For summary of the visibility impacts at Mammoth Cave National Park see Table below.

TGS and Cumulative Visibility Impacts
Mammoth Cave National Park

	Thoroughbred Generating Station Only (Fine Grid)			Thoroughbred Generating Station with 58 SO_2 PSD sources within 100 km of Mammoth Cave National Park (Coarse Grid)				
Change in Extinction	>5% Change in Extinction	Max Change in Extinction	Extinction Value at Max Change Mm^{-1}	>5% Change in Extinction	>10% Change in Extinction	Max Change in Extinction	Extinction Value at Max Change Mm^{-1}	TGS Change at Cumulative Maximum
1990- Number of days and magnitude of impact against the 20% cleanest days	1	7.40%	9.0	15	4	15.05%	18.4	5.35%
1992- Number of days and magnitude of impact against the 20% cleanest days	0	4.98%	3.0	19	2	12.52%	7.5	2.70%
1996- Number of days and magnitude of impact against the 20% cleanest days	1	7.47%	5.0	16	2	15.75%	10.6	7.75%

Based on the modeling results shown in the table above, there will be no adverse impact on visibility to the Class 1 area -Mammoth Cave National Park.

7. ADDITIONAL IMPACTS ANALYSIS

A. Growth Analysis

The proposed project, as reported in the application, will employ approximately 1000 personnel during the construction phase. The project will employ approximately 500 people on a permanent basis. It is a goal of the project to hire from the local community where possible. There should be no substantial increase in community infrastructure, such as additional school enrollments. The proposed project is also not expected to result in an increase in secondary emissions associated with non-project related activities. Thus, in accordance with PSD guidelines, the analysis of ambient air quality impacts need consider only emissions from the facility and its ancillary devices.

B. Soils and Vegetation Impacts Analysis

The project lies in an area of mainly post mining use. No significant off-site impacts are expected from the proposed action. Therefore, the potential for adverse impacts to either soils or vegetation is minimal. It is concluded that no adverse impacts will occur to sensitive vegetation, crops or soil systems as a result of operation of the proposed project.

C. Visibility Impairment Analysis

As discussed previously in Section C and 6(a) of the application the visibility at Mammoth Cave National Park was reviewed using the visibility function in the CALPUFF model. The projected change in visibility associated with the operation of the proposed facility has been determined to be minimal as a result of the multiple control technologies that will be utilized. Additionally, the Commonwealth of Kentucky has not determined any Class II areas in the vicinity of the proposed plant to have visual sensitive criteria established. Therefore, no significant change in visibility is expected from the facility.

D. Ozone

The Division does not anticipate violations of either the 1-hour or 8-hour ozone standard due to the construction of the Thoroughbred Generating Station based on the level of estimated emissions of nitrogen oxides and volatile organic compounds from proposed facility and the amount of these pollutants currently being emitted to the atmosphere in the area. Additionally, the Division's USEPA approved NO_x State Implementation Plan (SIP), and regulations approved to that SIP will ensure substantial NO_x reductions in the area.

8. CONCLUSION AND RECOMMENDATION

In conclusion, considering the information presented in the application, the Division has made a preliminary determination that the proposed source meets all applicable requirements:

1. All the emissions units are expected to meet the requirements of BACT for each significant pollutant. Additionally, each applicable emission limitation under 401 KAR Chapters 50 to 65 and each applicable emission standard and standard of performance under 40 CFR 60, 61, 63 and 64 will also be met prior to proposed/final permit.
2. Ambient air quality impacts on Class II areas are expected to be below the significant impact levels. No adverse impact is expected on any Class I area.
3. Impacts on soil, vegetation, and visibility have been predicted to be minimal.

A draft permit to construct and operate a nominal 1500 MWe pulverized coal fired electric generating facility in Muhlenberg County near Graham, Kentucky containing conditions which ensure compliance with all the applicable requirements listed above has been prepared by the Division and issued for public notice and comment. The Division recommends the issuance of the final permit upon satisfaction of the public comments. A copy of this preliminary determination will be made available for public review at the following locations:

1. Affected public at the Muhlenberg County Clerk's office.
2. Division for Air Quality, 803 Schenkel Lane, Frankfort.
3. Division for Air Quality, Owensboro Regional Office, 3032 Alvey Park Drive West, Suite 700, Owensboro, KY 42303.

CREDIBLE EVIDENCE

This permit contains provisions which require that specific test methods, monitoring or recordkeeping be used as a demonstration of compliance with permit limits. On February 24, 1997, the U.S. EPA promulgated revisions to the following federal regulations: 40 CFR Part 51, Sec. 51.212; 40 CFR Part 52, Sec. 52.12; 40 CFR Part 52, Sec. 52.30; 40 CFR Part 60, Sec. 60.11 and 40 CFR Part 61, Sec. 61.12, that allow the use of credible evidence to establish compliance with applicable requirements. At the issuance of this permit, Kentucky has not incorporated these provisions in its air quality regulations.